ATTACHMENT 3

Competition and Regulation in Bulk Power Markets
October 2000

Introduction

We are a group of public and private utilities, state regulators, environmental advocates, and ratepayer advocates from California to the Pacific Northwest. We operate in both and low cost states, with and without retail competition. Over the last five years, we learned a great deal, through industry restructuring, new regulations on transmission, more competition in generation, and, in some cases, open retail markets. Many of those lessons were compressed into a few months this summer, when electric power prices spiked far above historical norms. The purpose of this paper is to summarize some lessons learned, particularly this summer, and provide policy makers with some guidance on where we go from here.

Why a West Coast Alliance

Some may wonder why utilities and consumers in the relatively low cost Pacific Northwest and utilities and consumers in the relatively high cost California market should have similar concerns about restructuring. There are a series of reasons:

- First, the Pacific Northwest depends on the California market for winter purchases. The region is about 3,000 megawatts short in winter. This is partly offset by summer exports, but, in general, the region is short of supply during average water conditions. California has the opposite problem.
- Second, despite very limited change in industry structure, the Northwest has not added much new transmission or generation over the last ten years. This is mainly the result of low wholesale power prices (from 1995-1999) and regulatory uncertainty. California has also not added much generation over the last five years.
- Third, both California and the Northwest may be headed into an extended period of insufficiency in transmission and generation, and this is not in the interest of either region. Both regions must that new demand and supply-side resources are built in advance of acute need to remove market power, high prices, and volatility.
- Fourth, the Northwest and Southwest have economic and technical reasons to maintain their historical interdependence, based on load diversity, environmental factors, and the cost characteristics of existing resources.
- Finally, both California and the Northwest share some concern about having too many cooks in the kitchen. The new Administration, Congress, FERC, state legislatures, and state regulators will all focus attention in early 2001 on west coast electricity prices. This may be helpful, but it may also divert attention from key issues or make existing challenges more difficult to resolve.

It is also possible to put together a list of reasons that the two regions should not work together on a common approach:

- California could seek greater access to the hydroelectric resources of the Northwest (and Desert Southwest) by a combination of municipalizing existing investor-owned utilities and changing national rules on allocating federal power preferentially to public agencies and Northwest customers.
- In the short term, Northwest parties may see the California market as a profit-center in summer that overwhelms any downside risk in winter. Over the longer term, Northwest parties may be able to build generation for export more easily and cheaply than California can add new capacity, either through merchant plants, ISO capacity, or even new utility generation.

In our view, the benefits of cooperation outweigh either the downside risks or the potential, and largely theoretical, benefits of working separately.

Both regions need to find a new and better basis for adding generating demand and supply side resources and transmission. California sought to do this with a merchant plant model and a day-ahead market. Some things can be done to improve this model, but the steps taken by FERC, the ISO, or the CPUC are not sufficient. The Northwest has relied on the Bonneville Power Administration to add new resources, but BPA and the Northwest are understandably leery of asking a federal agency to play this role in a more competitive wholesale power market. Steps can be taken to transform Bonneville's role and ensure sufficient capacity is built in the Northwest to meet local needs and provide seasonal surpluses for export.

Second, nowhere in the United States is there such interdependence and such great difference in market structure. Some might argue that this calls for consistent national rules. Instead, we would argue that consumers in both regions are better off if they work toward a better common approach to capacity, efficiency, and transmission additions. Different approaches to competition do not argue for an over-arching federal role.

A Short History of Deregulation

The structure and regulation of the existing US electric utility industry vary substantially from state to state and region to region. In addition to investor owned utilities, we have federal power marketing agencies, municipally-governed utilities, cooperatives owned by their members, and public utility districts governed by local boards and state charters. These differences in ownership, structure, and governance have arisen over many decades. Differences in historical fuel use are very significant in explaining differences in cost from one region, or one utility, to another.

Federal efforts to open the wholesale market to greater competition began in 1979 with the passage of the Public Utility Regulatory Policies Act (PURPA). Congress enacted this legislation when electric utilities were warning of supply shortages, but were simultaneously frustrating the development of co-generation plants at industrial sites. PURPA required utilities to buy output from non-utility plants at avoided cost – the cost the utility would incur to produce the same energy. PURPA also required public and private utilities and state commissions to develop plans for ensuring full consideration of conservation, peak load management, peak load pricing, and other efficiency measures as alternative supply options.

PURPA had a very limited effect in the early 1980s. Classic co-generation required the use of either oil and gas, and both fuels were scarce and expensive. Most utilities also had huge nuclear or coal projects underway, and fears of shortage soon dissolved to an embarrassing amount of expensive over-capacity.

The law was implemented most aggressively in New England and California.. Both regions relied heavily on imported oil for existing generation and contemplated nuclear power to meet load growth. Avoided costs, however calculated, were high. Any alternatives on the supply and demand side seemed preferable. In these states, PURPA created a viable independent power generation industry and eliminated the possibility that utilities would monopolize the future generation market. Utilities were required to buy power that was cheaper than whatever they could build themselves, and pass that through to retail customers at cost. This undercut any opportunity for utilities to "gold-plate" rate-based generation or overbuild capacity to boost overall returns to stockholders.[1]

PURPA also summoned in a new decade of "least cost planning," where utilities and regulators tried develop plans for meeting electric demand at the lowest overall cost. Because lower sales and lower costs might mean lower profits, utilities and regulators looked at new forms of regulation that kept the utility whole.

The big surprise around the country in the early 1990s was the combination of sharp declines in gas price and huge improvements in the efficiency and reliability of gas turbine generation. Gas generation was suddenly cheaper than coal or nuclear, sufficiently reliable for base-load (around the clock) use, easy to site, easy to cool, and reasonably clean.

Some utilities built new gas generation, but most that needed new capacity looked to independent power producers. Individual utilities would sign a 30-year "PURPA contract" with an independent generator. The independent power producer would sign a long-term gas contract. The combination of the two made the plant so easy to finance

[1] While incentives to gold plate and overbuild were theoretically in place in the early 1970s, they'd pretty much vanished by the late 1970s and early 1980s when interest rates were higher than authorized rates of return for most investor owned companies. In that environment, every extra dollar borrowed had a price tag.

that Wall Street usually provided these plants with cheaper capital than utilities could get themselves.[2]

This model of independent generation was in full swing when Congress enacted the 1992 National Energy Policy Act (NEPAct). One small part of NEPAct directed FERC to authorize new "exempt wholesale generators" and ensure that utilities did not frustrate their development by denying transmission access.

FERC went well beyond these instructions when it finally issued Order 888 in April 1996. Order 888 required investor owned utilities to make available for common use all transmission that was surplus to a utility's firm retail load. This substantially expanded the scope and scale of the wholesale power market, at a time when fuel prices were low and there was surplus generation. In this environment, utilities and state regulators generally agreed that it made more sense to rely on spot market power purchases, rather than any new project, whether independent or utility-built, to meet growing demand.

Order 888 also made clear that any new resource acquisition by a utility might not be recoverable in retail rates. As a consequence, the market for new plants of any sort collapsed, including the "exempt wholesale generators" that were the original focus of NEPAct.

These rules and market conditions also put a crimp on utility conservation efforts that had been treated by many regulators as resource decisions. If a utility's total resource portfolio – including owned generation, contracts, renewables, and conservation – was over-market, any new investments that made the problem worse could be deemed unrecoverable by state regulators, by FERC, or by both. This uncertainty persists today.

It is argued that Order 888 "deregulated" the wholesale power market; it did not. Orders 888 and 889 defined the rules under which FERC might approve market pricing. They would do so if utilities could demonstrate they had functionally or administratively separated transmission management from other utility functions.

The Order may have invalidated specific tariffs charged by IOUs making long-term sales to other utilities, but allowed such utilities to recoup any associated stranded investment through a "wires charge." It laid the groundwork for eliminating all future tariffs for short-term surplus sales in the bulk power market.[3] It also had no effect on the price of power charged by vertically integrated utilities selling to retail loads.

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[2] Such plants could be financed with 80% debt and 20% equity, compared to the 50-50 split typical of regulated IOUs. These units were not necessarily cheaper over the long term than utility ownership, particularly if gas prices decline and the power purchase contract locks in supplies at higher prices. Utilities and regulatory commissions generally sought power prices indexed to gas commodity prices to avoid this outcome.

[3] While state or federal agencies did not regulate these sales, any proceeds over cost were generally rebated to ratepayers, so the incentive to profiteer was never very large. And the shoe occasionally shifts to the other foot, so profiteering was at least unseemly and potentially risky.

It may be useful to summarize exactly what has and has not been "deregulated" at this stage. Existing utility generation is still sold at cost to retail customers. Surplus generation may be sold at a regulated rate until FERC determines that transmission separation is effective. When FERC makes this determination, any price can be charged, though a utility's incentive to profiteer is limited, because state regulators can still credit net proceeds to customers instead of stockholders. New generation can be built by utilities, independent generators on contract, or merchant plant operators on speculation. Order 888 was not so much a step toward deregulation, but toward enhanced regulation of the transmission system to ensure that surplus generation from any source could reach any potential customer.

It is unclear at this stage whether this model is an improvement on PURPA. In the Northeast, wholesale prices have been high enough that new merchant plants can be profitably built and operated.[4] In the west, wholesale prices were too low to justify new merchant plant additions in the mid-1990s. This situation accounts for many differences in wholesale price volatility from one region to another.

Meanwhile, transmission built by utilities to serve firm retail loads is still available to those customers at cost. But FERC rules point to a transmission system that ultimately cannot distinguish between firm retail loads and commercial transactions. This was perceived as the only long term way to prevent self-dealing and discrimination. But it adds new uncertainties to transmission construction: who is responsible, who would evaluate the reasonableness of these investments (FERC or the states), and what rules govern cost recovery? It also adds uncertainties over reliability of service to retail loads. State and federal regulators and public and private utilities are still struggling with the uncertainties of cost recovery for new resources and new transmission.

Meanwhile, in higher cost states, like California, the political pressure for further restructuring proved irresistible. In that state, wholesale bulk power market averaged 2.5 cents/kWh and the commodity portion of electric bills stood at 7.5 cents/kWh. California was the first large state to adopt comprehensive restructuring legislation. This was followed quickly by legislation in several New England and Midwest states. All contemplated significant transition periods to recover stranded costs, create new institutions, and prepare for a much more sophisticated electric marketplace.

Experiments in Retail Competition

Borrowing heavily from the United Kingdom, the California PUC and then state legislature adopted rules and legislation (AB 1890) to introduce retail competition in electricity. The changes included:

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[4] This situation clearly applied in the Northeast in the mid-1990s, where new gas plants could be built and operated more cheaply than existing coal plants. With higher gas prices in the Northeast, the case is not so clear.

- Creation of a new power market (the PX) that would clear, at a market price, nearly all kilowatt-hours sold in the state, not just those that were surplus to retail customer needs. In taking this action, the legislature passed to FERC the authority to determine whether to allow market pricing. FERC did.
- Creation of an independent system operator (Ca ISO) to manage flows on the transmission system, and protect commerce and reliability, also under FERC jurisdiction.
- Requirements on investor owned utilities to sell their existing power plants to unregulated "exempt wholesale generators." IOUs were also required to sell all remaining generation to, and buy all power for customers from the new PX. (Both of these steps were taken to prevent abuse of market power by incumbent utilities. They also ensured that the PX would be a deep, transparent market that gave all customers the scale and scope benefits of a huge wholesale marketplace.)
- IOUs were not permitted to build new generation or do long term power contracts, either of which could trigger questions about the role of the IOUs in the marketplace and result in prudence reviews. New generation would be built when prices in the PX reached levels that made merchant plants profitable.
- Stranded costs were recovered, mainly through a complex refinancing mechanism. Total retail prices for smaller consumers were reduced 10 percent and capped temporarily, as part of the deal, roughly through 2001. After stranded costs are recovered, the cap is removed and consumers either buy directly from power marketers or pay PX prices.

Many other features of the legislation could be discussed, but the purpose here is to focus on whether the changes in the bulk power market have failed or succeeded, and why.

In the mid-1990s, residential customers of California IOUs paid an average of 11.5 cents/kWh, perhaps 50 percent more than the national average.[5] The commodity fraction of the bill, as established in regulated rates, was about 7.5 cents/kWh, leaving 4.0 cents/kWh for transmission and distribution. Electricity in the wholesale market stood at about 2.5 cents/kWh. Prices were low because of surpluses in western generation, surplus gas capacity, and surplus pipeline capacity. In that environment, marginal fuel costs (roughly 2.5 cents/kWh) set short-term market prices.

Investor owned utilities were understandably reluctant to simply lose, or write off, the difference between this short-term price (at 2.5 cents/kWh) and the energy component of retail rates (7.5 cents/kWh). Depending on future projections, this 5 cent/kWh gap

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[5] At the beginning of the 1970s oil crisis, most California generation was oil-fired. By the standards of the time, this capacity would need to be replaced *and* new growth met by coal or nuclear power. There was no coal in California, and no railroad capacity to import it. Thus, by 1974, plans were well underway for 30-60 GW of nuclear capacity in the state by 2000. The sheer physical and financial impossibility of this undertaking, given fresh water availability and seismic risks, led to aggressive regulation that many wrongly blame for high prices. This situation was bound to lead to high prices, however the industry was regulated.

represented an estimated $25 billion for the three California IOUs.[6] In addition, the utilities argued that 2.5 cents/kWh wasn't a good long-term price, because it did not include capital costs or reserves. Moreover, the prudence of their investment decisions in nuclear and PURPA capacity had been carefully weighed over 30 years by the CPUC. They surely should be able to recover the costs associated with their obligation to meet all retail loads. Consumer advocates countered that just because a plant was in rate base didn't mean utilities were entitled to profits forever. The CPUC and Legislature compromised on a refinancing scheme that essentially eliminated earnings and income taxes from these former assets. Whatever the merits, it is clear that any other conclusion would have resulted in protracted litigation.

The approach (called "securitization") essentially allowed the IOUs to refinance the $25 billion (or 5 cent/kWh) difference between their generating costs and current and projected wholesale market prices. This permitted an immediate 10 percent rate reduction. This step could have been taken without restructuring, but was central at the time to the political deal. The consequences to the average California residential electric bill are shown below, in cents per kilowatt-hour:

	Pre-1890	*Post-1890*	*1999*	*2000*	*2001*
Bulk power	7.5	2.5	2.5	3-10	3-10
Stranded cost	0.0	5.0	4.0	4.0	0.0
Trans/dist	4.0	4.0	4.0	4.0	4.0
Total	11.5	11.5	10.5	+10.5	???

Some observations might be made. AB 1890 did not change prices in the wholesale power market. To win a new retail customer, power marketers had to offer a price below 2.5 cents/kWh (the 1997-1999 PX price). This was unlikely for two reasons: it represented the marginal operating cost of essentially depreciated plant; and such a producer could get 2.5 cents/kWh selling to the PX without the additional transaction cost of retail service.[7] All immediate savings are associated with securitization of stranded cost (bringing 5 cents/kWh to 4 cents/kWh). Transmission and distribution costs are unaffected by retail competition.

In 2000, stranded costs are still being recovered, bulk power prices have risen substantially, and retail prices are capped. The long term question is what price is necessary to develop new merchant plants. Utility generation or independent generators with long term contracts could probably be built for 3-5 cents/kWh, using either gas or wind, or both. We do not know nearly as much about the hurdle rate required to finance a merchant plant dependent on day-ahead PX prices.

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[6] California regulators wisely avoided much nuclear over-investment, but did commit substantially to gas, geothermal, and wind generation pegged slightly below the cost of reactors or existing oil-fired plants.

[7] This did not stop Enron and many others from spending an estimated $140 million to learn this lesson.

Critics of the California model also argue that the intricate relationship between stranded cost recovery, PX clearing price, and the retail rate cap diminished competitive opportunities for direct access and reduced consumer incentives to conserve. Both points are true, but probably marginal or irrelevant. Doing it otherwise would have put either stranded cost recovery or the retail rate cap at risk, both of which were fundamental elements of the original political deal.

How Has it Worked?

Price Volatility and Market Power.

In enacting and implementing AB 1890, the legislature and CPUC were fully cognizant that the new California power market could be both volatile and vulnerable to market power. California regulators took steps to address this issue, through privatization of much utility generation, creation of a PX, creation of an independent transmission system operator, new transmission prices, and designation of must run plants in certain geographic areas.

California regulators also realized that some power plants in specific sub-regions of the state had market power regardless of ownership, because of transmission constraints. These plants were designated "must run," and comprised about 30-40 percent of total capacity. PURPA, hydro, and nuclear capacity was designated "must run," to ensure cost recovery. The combination, however, took a lot of capacity out of the day-ahead PX market, reducing the clearing price to zero in some hours of the year (total demand equals must take plus must run).

In the first few years, it could be argued that many features of the model worked. Stranded costs were largely recovered. The PX worked, albeit with teething problems. The ISO also worked, but faces enduring problems with unexpected flows and congestion and challenges in pricing transmission and reliability services. Retail access was not a great success, for reasons that are at least obvious in hindsight.

In 2000, California's investor owned utilities or their customers are going broke. In the first few years of PX operation, bulk power prices averaged 2-3 cents/kWh, spiking above 10 cents/kWh for a small number of hours per year. This was expected. But 2000 brought disaster: 34 stage two emergencies, bulk power prices averaging more 10 cents/kWh for the period May through October. San Diego Gas and Electric successfully recovered it stranded costs by April 2000, removed the retail price cap, and passed PX prices directly through to customers. This central feature of AB 1890 (and of essentially all other US retail competition legislation) didn't survive two months in the San Diego sun.

Meanwhile, the state's two largest utilities – SCE and PG&E – haven't quite recovered their stranded cost, so they are dutifully buying their power from the PX at a price much higher than the retail rate cap. Both IOUs are bleeding money so quickly that they could be technically insolvent before the legislature reconvenes in January 2001.

Retail choice. In California, every retail customer has automatic access to the PX through the incumbent utility. This theoretically offered full access to the benefits of a large wholesale power market, and simultaneously ensured that choice would not leave smaller customers behind. This took place under a complicated and transitional retail price cap that was not easy on competitors, but worked reasonably well in stable wholesale markets.

In spring 2000, some 19% of industrial customers of IOUs bought power through bilateral contracts. Only 1.9% of residential customers bought outside the PX, and only 2.2% of the total customer base (including residential, commercial, industrial, and agricultural loads of IOUs) had direct contracts, though this market was in its third year of operation.

By the end of August 2000, direct access loads were down substantially, not because the PX was a good deal, but because direct access providers could not meet their obligations. At the end of August, only 13% of industrial customers had bilateral contracts. The number of commercial customers was similarly down nearly 50 percent.

In either case, the model of full retail choice for small and medium customers did not work well in a relatively low-cost surplus market. It will work even less well in a volatile high cost market, because producers will shift sales from retail customers to the PX, and intermediate marketers will largely disappear.

Proponents of full retail choice must argue that price volatility in the bulk power market is just a temporary phenomenon, that San Diego customers were wrong to demand reinstitution of a retail price cap, and that temporarily high prices will bring lower costs over time. There may be some textbook appeal to this argument; demand elasticity, load shifting, and new power plants would be helpful in reducing market power and lowering consumer costs. But it is hard to see patience winning any votes in the Legislature or CPUC.[8] Retail customers, large and small, want more reliability and price stability than California's restructured market can currently provide.

Options for Fixing the Mess

California regulators can and will address the current problem. In the next six months, it is inevitable that California regulators, the Governor, and state legislature will amend AB

[8] It is also worthwhile to remember that we did not see spectacular demand reductions with either year-around high prices for electricity (e.g., on Maui or Long Island) or in states that passed through high peak power prices (e.g., California and New York) under traditional regulation. Divided incentives still infect the demand-side market, restructured or not.

1890. Under current law, California's regulated utilities are headed toward technical insolvency, perhaps by early 2001. The IOUs cannot recover high PX clearing prices in retail rates, and AB 1890 gives no clear guidance on whether this liability rests with customers or stockholders. Under 1890, PG&E and SCE may be entitled to lift their retail rate caps before next summer, which may help the companies but puts 75 percent of the state's ratepayers in San Diego's shoes. The unacceptability of either outcome presents a compelling deadline.

Several interim fixes are underway, including caps on prices paid by both the PX and ISO. These must be approved by FERC, and the agency has reluctantly done so. But caps also add a new regulatory uncertainty to merchant plant development. If regulators can impose a $250/MWh price cap, they can also impose a $100/MWh price cap, and so on.

Another potential fix would allow utilities to buy short and long term forward contracts or hedges against PX volatility. This also raises concerns in the merchant plant industry, because it will diminish liquidity and price transparency in the PX. It also frustrates power marketers, who are less able to peg their prices to a transparent alternative.

Nevertheless, regulators are likely to require utilities to do more long term contracting. There are three key problems with this strategy:

- First, forward markets aren't offering a much better price than this year's PX, so volatility may be lessened, but prices aren't much improved.
- Second, to have much affect, utilities would need to shift a huge amount of load, in the short term, into contracts and out of the PX. This is not a 500-1000 megawatt problem; it's a 10,000-20,000 megawatt problem.
- Finally, and most importantly, there are no rules for how regulators would judge the prudence of, or allow costs to be recovered from, long term hedges or contracts. The companies would be required to pass through the benefits of good decisions, but could be penalized by regulators (or could lose customers) as a consequence of bad decisions.

From this perspective, contracts or hedges are a potential new stranded cost. The same risk applies to new utility investments in conservation, distributed generation, or real-time metering. All of these could be essential tools for regulators and utilities trying to meet demand at reasonable cost over the next few years.

There are only a few choices to ensure reasonable prices and adequate capacity. The CPUC and FERC could "pre-approve" any and all contracts entered into by utilities, and make new provisions to recover any new stranded costs if they occur. This approach is littered with fatal flaws for the regulators and the utilities. The CPUC and FERC could demand heavy reliance on contracts, and allow utilities a return on purchased power and a higher return on distribution assets to compensate for the business risk. This is possible, but awkward.[9] It is also possible to imagine the Legislature or CPUC setting a new, permanent, higher retail rate cap under which utilities could do long term resource procurement, but it is extremely hard to pick the right number and provide the utility with proper incentives.

Finally, the CPUC and state legislature can rewrite AB 1890 to substitute a new utility model for full retail wheeling. This option deserves some attention. Under a full retail wheeling model, utility investments in generation, conservation, distributed generation are more risky and customer investments in these technologies are less likely.[10] This option would require state regulators to redefine the utility's role and customers' rights, including cost recovery, customer eligibility for long term cost-based service, and new rules to limit the frequency of supplier changes. One significant characteristic of this model is that all electricity sold to customers taking cost-based or "default" service from utilities reverts from FERC to exclusive state jurisdiction. Transmission used in support of such sales may also revert to the state.

One model, inherited from natural gas, is a "core/non-core" model, where utilities have the obligation to serve smaller customers and have a long-term obligation to meet their needs, subject to regulatory review. Core customers must either have a parallel obligation to take, or provisions must be made to recover potential new stranded costs. Non-core customers, over a certain consumption threshold, shop for themselves. They could presumably cut the same long-term deals with new and existing power plants that utilities would. Utilities have no obligation to acquire resources on their behalf.

Another approach is a "portfolio model," where the utility plans for a mix of resources that are aligned with customer preferences and utility obligations. Customers commit by contract to services that are matched to the utility obligation. In this approach, customer might choose green power, five-year stable rates, daily price volatility, or other options that form the basis of a utility resource portfolio. There would not be any obligation to acquire resources that are beyond the contractual commitments of customers.[11]

Both models are relatively easy to implement in a static world, but pose challenges to implement when new customers appear, customers move, and customers merge or go bankrupt. Regulators and utilities have tools to address these issues, and must consider them.

Another alternative is to put the Independent System Operator in charge of long term resource procurement to meet anticipated system loads. The ISO could run an auction process to buy dispatchable power from new plants to meet urgent system conditions. In off-hours, the merchant plant would be operate normally. The modest, but steady revenue

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[9] Utility customers are not particularly well served by paying a merchant plant rate of return, which is higher than a utility rate of return, plus a higher utility rate of return to compensate for higher utility business risks. Traditional utility-owned rate-based generation should at least deserve consideration.

[10] See attachment.

[11] Industrial customers could also be served under this model.

stream from the ISO would make finance easier. Procurement of dispatchable capacity by the ISO would make reduce market power in times of shortage, dampen the volatility in the short-term market, and discourage re-monopolizing of the generation market by incumbents. But the ISO is not set up to play this role under existing law, and it could conflict with its independent transmission management mission.

Some would argue that FERC is the only organization that can or should fix California's wholesale market problem. The agency bears some responsibility for California's problem. The state's wholesale market structure – with a PX and ISO – was borrowed from Britain and passed into law in Sacramento. But both the PX and ISO are under full FERC jurisdiction, and the agency has approved virtually every significant policy or tariff of the PX and ISO. When FERC was satisfied that there would not be abuse of market power in either generation or transmission, the agency approved the "deregulation" of wholesale market prices.

In past years, FERC has espoused the model of full retail competition, with all power sold at market under their limited supervision, and all transmission also operating under FERC rules. The agency has now determined that the bulk power market in California, at least, is not "workably competitive." They have reluctantly proposed wholesale price caps as an interim measure, but it is not clear that wholesale price caps fix either the supply or price problem. They clearly do not address the problems on the retail side.

FERC may be dissatisfied with hybrid solutions that allow some electricity to be sold at market and some to be sold at cost. They could take steps to frustrate re-institution of default provider rules or long-term at-or-near-cost utility resource acquisition, because of the negative impact on new or existing merchant plants. But the political climate probably favors home-grown second-best solutions, and the one we seem to be heading toward in electricity is not all that different from the one that FERC engineered in natural gas.

One complexity involves transmission. Is an RTO necessary or desirable in a market where some power is sold at cost to default customers and some is sold at market to others? Does the RTO assign a higher transmission priority to the firm retail customers, or must these customers compete for access to transmission with commercial transactions? FERC would probably go with the latter and state regulators would probably go with the former.

The bottom line is that ISOs or RTOs, whether publicly owned or privately owned, under FERC jurisdiction or under state jurisdiction, don't necessarily alleviate market power, facilitate competition, improve customer reliability, or reduce price spikes. They can add transaction costs and confusion. On this point we don't have much guidance, except to say that they are probably desirable when it can be shown that transmission prices truly frustrate low cost generation from entering the marketplace. And they are probably undesirable in places where transmission prices do not seriously limit generators from reaching load. In our view, this debate needs to focus on consumers, and what they need and want, instead of the ideological battlefield of competing producers.

Attachments

Conservation, Self Generation, Distributed Generation, and Retail Wheeling

It is often argued that retail competition in electricity will bring about a technological revolution in electricity use. Fuel cells, micro-turbines, and new conservation technologies will gain greater market share. This perspective is largely inherited from experience in telecommunications, and the application to electricity deserves comment.

California and Pacific Northwest policy makers were among the first in the nation to identify role of energy efficiency in meeting future electric demand. In the mid-1970s, utilities were uninterested, unprepared, or opposed to any active role in energy efficiency. Most of the focus at that time was on building and appliance efficiency codes, all of which brought substantial savings to consumers at little or no cost to utilities.

By the early 1980s, partly as a result of PURPA's success and nuclear failures, regulators and utilities began to explore a more active role for utilities in acquiring conservation. Utilities had a customer relationship; they understood, or at least potentially understood, efficiency alternatives; and, at the time, they saw the high marginal cost of new resources. Customers did not. In this environment, it was easy to make the case that ratepayers were better off if utilities made substantial investments in energy efficiency. But stockholders weren't necessarily better off. For the most part, utilities could not make more money selling less power. It could be argued that they would lose less money by doing conservation rather than supply investments, and some followed this advice. Many states experimented with regulatory reforms to address this conflict.

This was the least-cost era of utility planning, and it may have lasted a decade. By the mid-1980s, wholesale power prices had dropped, but retail rates had risen. This apparent contradiction arose when utilities completed reactors (and put them into rate base) at roughly the same time natural gas prices fell. Retail rates were high; marginal costs were low. Even the best utilities lost their interest in conservation programs. They did not seek new capacity; instead their thoughts turned to load retention.

Some industrial customers facing high retail rates threatened to self-generate with ample supplies of cheap gas available. The threat was real enough that utilities reduced industrial rates to cover marginal costs of supply plus a small contribution to fixed system costs; this was cheaper, even in the eyes of low income advocates, to losing the customer altogether. Utilities with long-standing commitments to energy efficiency slashed their conservation programs, worried about rate pressures and balance sheets that now favored increased sales over increased efficiency. Programs that did survive were justified as a new form of customer service, rather than least cost resource additions.

These conflicts also affected public utilities. When marginal costs were above retail rates, and the utility had nothing under construction, conservation investments were generally a winning bet for the utility and its customer-owners. When the balance shifted, a utility manager could still offer conservation programs, but had to have the gumption to compromise the agency's bottom line for the bottom line of customers.

One lesson from this history is that utilities are powerful but uncertain partners in assuring the development of socially cost-effective conservation. They may have an incentive to participate when marginal cost is above average cost and regulatory disincentives are fixed. They have precious few incentives when marginal costs are below average costs, regardless of regulatory treatment.

The prospect of retail wheeling adds further complications. Investments in energy efficiency at customer sites may not be recoverable, and the benefits could accrue to another energy provider. As a consequence, many cheap energy efficiency investments do not get made.

For these reasons, energy efficiency advocates sought, and, for the most part, were able to incorporate "system benefit charges" in retail wheeling legislation. These charges build a bank account to fund low-income programs, energy conservation programs, energy research, and renewable resources.

It is worth summarizing, in light of this history, current prospects for efficiency improvements and distributed generation. In the first era (late 1970s to early 1980s), retail rates were relatively low and new resources were much higher in price. The onus was on utilities to seek efficiency investments cheaper than the cost of new resources. But the incentive structure did not favor those investments, particular if they undercut the viability of a resource the utility was building. In the second era, the burden shifted to retail customers, who could avoid high retail rates (exceeding 15 cents/kWh in some parts of the US) through conservation or self-generation.

The current era of retail competition adds a few new wrinkles. It does not change the total retail rate for electricity, but it does substantially reduce the incentive to invest in conservation or on-site generation. In the California example, a customer paying 11.5 cents/kWh for bundled electricity might have saved nearly the full amount, but now saves only the unbundled amount (2.5 cents/kWh) by using less. Partial self-generation (e.g., micro-turbines, fuel cells, diesel engines, or photovoltaics) is discouraged because the customer saves only the energy fraction of an unbundled bill. Retail competition does nothing to encourage (or discourage) complete self-generation (through micro-turbines or fuel cells); the full amount can still be saved. If these technologies did not develop rapidly under the old regime in high cost states, there is no reason to think – other than pure faith in technology – that retail competition improves their standing.

In the current world of higher and volatile energy prices and open retail access, consumer incentives for conservation and distributed generation have been dampened by unbundling, and utility incentives are extremely unclear.

Retail access has also shifted the focus of conservation funding from least cost resource acquisition by individual utilities to social incentives in historically important programs. The amount spent was a political compromise. It might be more or less than what was efficient or necessary. But the amount of spending is not related to value or changes in wholesale electricity price. The programs tend to focus on "market transformation" efforts that have a long term focus and little near-term payoff. The funding may be substantial, but may not target current prices or problems. It is possible and desirable in a high priced environment to resuscitate targeted utility conservation programs, but cost recovery is uncertain and programs could be duplicative.

The challenge for distributed generation is more daunting. The potential for distributed generation (as opposed to self-generation) was originally identified in the late 1970s by John Peschon (for a Swiss utility) and Carl Weinberg (for a California company). The key common conclusion was that small generators in the distribution system might offset not only new central station generation, but improve end-use reliability and offset substantial new transmission and distribution cost. But this conclusion was highly dependent on many site and system characteristics that made analysis and generalization difficult.

In addition, both utilities and regulators were stuck in a paradigm where investments in generation, transmission, and distribution were judged separately. Modeling tools for integrating the three were primitive, and interest collapsed with the development of a competitive wholesale power market model that could not assign clear value to generation built within the distribution system. The conundrum continues today, but is made worse by retail competition. There is no clear way for utilities or customers to capture the value of investments in distributed generation that could offset PX purchases, ancillary service costs, transmission investments planned by ISOs, and distribution system investments made by utilities.

Customers facing exorbitant real time electricity prices have a big incentive to reduce use, but they have generally responded with shutdowns, curtailment, and outcry, not efficiency improvements. It is correct that the electricity marketplace would be more efficient if all customers could see and respond instantly to higher prices. But it takes a strong stomach to say that the solution to California's problem is to drastically increase retail electric rates and await a positive revolution. We are also finding that some large customers that were happy a few years ago with real-time market prices and interruptible rates cannot handle that situation today.

If electricity is just a market commodity, then it follows that, at some price, it would be just fine if no electricity was consumed. And, at some other price, it would be fine if demand doubled. Both examples are absurd but make the point that a stable electric grid is a common good, not a mere commodity.

It is also worth remembering the lackluster influence of either peak load pricing or high year-around retail rates (e.g., Long Island or Hawaii) on self-generation or efficiency investments. The pervasive institutional barriers that block socially cost-effective efficiency investments – for example, divided incentives between builders and buyers and landlords and tenants – are still in place today, and retail competition generally makes them worse. The same situation applies to any of the new generation technologies, including fuel cells, micro-turbines, and photovoltaics.